BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

------ In the Matter of ------	)	
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PUBLIC UTILITIES COMMISSION	)	DOCKET NO. 2018-0088
	)	
Instituting a Proceeding To	)	
Investigate Performance-Based	)	
Regulation.	)	
	)	

DECISION AND ORDER NO. 38429

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PUBLIC UTILITIES COMMISSION	DOCKET NO. 2018-0088
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DECISION AND ORDER

By this Decision and Order,[1] the Public Utilities Commission ("Commission") establishes a suite of additional performance mechanisms, pursuant to Order No. 37969, filed on

[1]The Parties to this proceeding are HAWAIIAN ELECTRIC COMPANY, INC. ("HECO"), HAWAII ELECTRIC LIGHT COMPANY, INC. ("HELCO"), MAUI ELECTRIC COMPANY, LTD. ("MECO")(collectively, HECO, HELCO, and MECO are referred to as "the Companies") and the DIVISION OF CONSUMER ADVOCACY ("Consumer Advocate"), an ex officio party, pursuant to Hawaii Revised Statutes § 269-51 and Hawaii Administrative Rules § 16-601-62(a). Additionally, the Commission has granted the following entities intervenor status: CITY AND COUNTY OF HONOLULU, COUNTY OF HAWAII, BLUE PLANET FOUNDATION ("Blue Planet"), LIFE OF THE LAND ("LOL"), DER COUNCIL OF HAWAII, HAWAII PV COALITION, HAWAII SOLAR ENERGY ASSOCIATION (collectively, the "DER Parties"), and ULUPONO INITIATIVE, LLC ("Ulupono"). Order No. 35542, "Admitting Intervenors and Participant and Establishing a Schedule of Proceedings," filed June 20, 2018. The Commission has also granted participant status to ADVANCED ENERGY ECONOMY INSTITUTE. Id.

September 17, 2021.[2] Specifically, the Commission approves: (1) a new Performance Incentive Mechanism ("PIM") to incentivize maintenance of reliable service associated with generation-based disruptions; (2) a new PIM to incentivize the timely completion of the interconnection requirements study ("IRS") process for large-scale renewable energy projects; (3) a new Shared Savings Mechanism ("SSM") to incentivize cost control over the Companies' fossil fuel, purchased power, and Exceptional Project Recovery Mechanisms ("EPRM") costs (collectively, "non-ARA costs"); and (4) a modification and extension of the interim Grid Services PIM[3] through December 31, 2023.

In addition, the Commission instructs the Companies to prepare and submit: a detailed fossil fuel retirement report outlining necessary steps to safely and reliably retire Waiau Units 3 & 4 and the Kahului Power Plant, as well as other potential plant retirement candidates within the first Multi-year Rate Period ("MRP"); and a functional integration plan ("FIP") for Distributed Energy Resources ("DER") to increase transparency into the Companies' plans and progress for utilizing cost-effective grid

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[2]See Order No. 37969, "Introducing Staff Proposal and Establishing Procedural Schedule For the Performance-Based Regulation Working Group," filed on September 17, 2021 ("Order No. 37969").

[3]See Decision and Order No. 37507, filed on December 23, 2020 ("D&O 37507"), at 106-114.

services from DERs and ensure that the necessary functionalities and requisite technologies are in place to do so, which shall be filed in the DER docket.[4] The Commission also instructs the PBR Working Group ("Working Group") to continue collaborating on a number of issues prioritized by the Commission, as discussed below.

The Companies shall submit draft tariffs to implement the above PIMs within one month of this Decision and Order for the Commission's review and approval.

I.

BACKGROUND

On July 9, 2021, the Commission notified the Parties that it would be convening the Working Group to consider and develop additional performance mechanisms to address the following areas of concern ("AOC"): Grid Reliability; Timely Retirement of Fossil Fuel Generation Units; Interconnection of Large-Scale Renewable Energy Projects; and Cost Control for Fossil Fuel, Purchased Power, and Other Non-ARA Costs.[5]

[4]Docket No. 2019-0323.

[5]See Letter From: Commission To: Service List Re: Docket No. 2018-0088; Notice to PBR Working Group of Commission's Intent to Develop New Performance Mechanisms, filed July 9, 2021.

Soon thereafter, on September 17, 2021, the Commission issued Order No. 37969, which introduced a Commission staff proposal ("Staff Proposal") that contained a conceptual slate of PIM and SSM ideas for the Working Group to consider.[6] Order No. 37969 also introduced a fifth AOC, "expedient utilization of grid services from demand-side resources," and established a procedural schedule for the Working Group's consideration of the five AOCs.[7]

In response to concerns raised by the Parties about the procedural schedule, the Commission subsequently issued Order No. 38078 on November 19, 2021, which modified the procedural schedule.[8]

On December 22, 2021, the Commission issued Order No. 38145, which slightly modified the schedule to re-schedule a Commission-hosted workshop. No other deadlines were affected.[9]

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[6]See Order No. 37969, attachment titled "Staff Proposal for Development of Priority Performance Mechanisms." For purposes of this Decision and Order, "Staff Proposal" shall refer to the attachment to Order No. 37969.

[7]Order No. 37969 at 4-5.

[8]Order No. 38078, "Resuming Proceedings and Modifying the Procedural Schedule," filed on November 19, 2021 ("Order No. 38078"). See also Order No. 38049, "Suspending the Procedural Schedule," filed on November 2, 2021.

[9]Order No. 38145, "Modifying the Procedural Schedule," filed on December 22, 2021.

Pursuant to the procedural schedule established in Order No. 38078, as modified by Order No. 38145, the Parties engaged in a collaborative Working Group process during November 2021 through February 2022. This consisted of party-led Working Group meetings, interspersed with three Commission-hosted check-ins.[10]

On February 8, 2022, the schedule shifted to a more formal evidentiary phase, beginning with Parties submitting their Preliminary Statements of Positions ("PSOPs") addressing proposals for the AOCs.[11]

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[10]See Order No. 38078 at 4-5.

[11]See Order No. 38078 at 4. See also, "Ulupono Initiative LLC's Phase 3 Preliminary Statement of Position; and Certificate of Service," filed on February 8, 2022; "Hawaiian Electric Companies' Preliminary Statement of Position; Exhibits 'A' Through 'B'; and Certificate of Service," filed on February 8, 2022; "Blue Planet Foundation's and Life of the Land's Preliminary Statement of Position; and Certificate of Service," filed on February 8, 2022; "Hawaii PV Coalition, Hawaii Solar Energy Association and Distributed Energy Resources Council of Hawaii Initial Statement of Position on Staff Proposal for Development of Priority Performance Mechanisms; and Certificate of Service," filed on February 8, 2022; and "Division of Consumer Advocacy's Preliminary Statement of Position on Staff Proposal for Development of Priority Performance Mechanisms Dated September 17, 2021; and Certificate of Service," filed on February 8, 2022.

Pursuant to Order No. 38145, the Parties exchanged information requests ("IRs") during February 2022, and submitted responses on March 4, 2022.[12]

On March 10, 2022, the Commission issued Order No. 38267, further modifying the procedural schedule to allow the Parties additional time to submit supplemental IRs ("SIRs") and further develop the record.[13]

Pursuant to Order No. 38267, the Parties exchanged SIRs on March 16, 2022, and submitted responses on April 1, 2022.

On April 8, 2022, the Parties submitted their Final Statements of Position ("FSOPs").[14]

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[12]Response to IRs shall be designated as follows: [Party] Response to [Party]-IR-XX. Filing dates shall be included in the first instance of use.

[13]Order No. 38267, "Further Modifying the Procedural Schedule," filed on March 10, 2022 ("Order No. 38267"). Responses to SIR shall be designated as follows: [Party] Response to [Party]-SIR-XX. Filing dates shall be included in the first instance of use.

[14]See "Hawaii PV Coalition, Hawaii Solar Energy Association and Distributed Energy Resources Council of Hawaii Final Statement of Position on Staff Proposal for Development of Priority Performance Mechanisms; and Certificate of Service," filed on April 8, 2022 ("DER Parties FSOP"); "Blue Planet Foundation's Final Statement of Position; and Certificate of Service," filed on April 8, 2022 ("Blue Planet FSOP"); "Ulupono Initiative LLC's Phase 3 Final Statement of Position; and Certificate of Service," filed on April 8, 2022 ("Ulupono FSOP"); "Life of the Land's Joinder to Ulupono Initiative LLC's PBR Phase 3 Final Statement of Position; and Certificate of Service," filed on April 8, 2022; "Hawaiian Electric Companies' Final Statement of Position; Exhibits 'A' Through 'F'; and Certificate of Service,"

On April 12, 2022, the Commission issued a notice for a Prehearing Conference, scheduled for April 20, 2022, for a hearing for this phase of the proceeding.[15] Relatedly, on April 13, 2022, the Commission issued a letter to the Parties providing further details about the format of the hearing, which would utilize a panel format and be held virtually.[16]

On April 21, 2022, the Commission issued Order No. 38334, which memorialized the results of the Prehearing Conference.[17]

The Commission held a panel hearing from April 26 thru 27, 2022.[18]

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filed on April 8, 2022 ("Companies FSOP"); and "Division of Consumer Advocacy's Final Statement of Position on Staff Proposal for Development of Priority Performance Mechanisms, Filed September 17, 2021," filed on April 8, 2022 ("CA FSOP").

[15]Letter From: Commission To: Service List: Re: Docket No. 2018-0088, In re Public Utilities Commission, Instituting a Proceeding to Investigate Performance-Based Regulation - Notice of Prehearing Conference, filed on April 12, 2022.

[16]Letter From: Commission To: Service List: Re: Docket No. 2018-0088, In re Public Utilities Commission, Instituting a Proceeding to Investigate Performance-Based Regulation - Further Information Regarding Hearing, filed on April 13, 2022.

[17]Order No. 38334, "Prehearing Conference Order," filed on April 21, 2022 ("Order No. 38334").

[18]See Letter From: Commission To: Service List Re: Docket No. 2018-0088 - Instituting a Proceeding to Investigate Performance-Based Regulation - Notice of Hearing Recording, filed on April 28, 2022. Links to a recording of the hearing are available on the Commission's YouTube webpage. See id.

Pursuant to the modified schedule in Order No. 38267, the Parties filed Post-Hearing Briefs on May 11, 2022.[19]

On May 25, 2022, pursuant to Order No. 38267, the Parties filed their Post-Hearing Reply Briefs.[20]

Pursuant to the procedural schedule set forth in Order No. 37969, and as further modified by Order Nos. 38078, 38145, and 38267, there are no further procedural steps remaining and this matter is ready for decision-making.

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[19]See "Ulupono Initiative LLC's Phase 3 Post-Hearing Brief; and Certificate of Service," filed on May 11, 2022 ("Ulupono Post-Hearing Brief"); "Life of the Land's Joinder to Ulupono Initiative LLC's Phase 3 Post-Hearing Brief; and Certificate of Service," filed on May 11, 2022; "Blue Planet Foundation's Post-Hearing Brief; and Certificate of Service," filed on May 11, 2022 ("Blue Planet Post-Hearing Brief"); "Hawaii PV Coalition, Hawaii Solar Energy Association and Distributed Energy Resources Council of Hawaii Phase 3 Post Hearing Brief; and Certificate of Service," filed on May 11, 2022 ("DER Parties Post-Hearing Brief"); "Hawaiian Electric Companies' Post-Hearing Brief; Exhibits 'A' Through 'B'; and Certificate of Service," filed on May 11, 2022 ("Companies Post-Hearing Brief"); and "Division of Consumer Advocacy's Post-Hearing Brief," filed on May 11, 2022 ("CA Post-Hearing Brief").

[20]See "Ulupono Initiative LLC's Phase 3 Post-Hearing Reply Brief; and Certificate of Service," filed on May 25, 2022 ("Ulupono Post-Hearing Reply"); "Division of Consumer Advocacy's Post-Hearing Reply Brief," filed on May 25, 2022 ("CA Post-Hearing Reply"); "Hawaii PV Coalition, Hawaii Solar Energy Association and Distributed Energy Resources Council of Hawaii Phase 3 Post-Hearing Reply Brief; and Certificate of Service," filed on May 25, 2022 ("DER Parties Post-Hearing Reply"); and "Hawaiian Electric Companies' Post-Hearing Brief; Exhibits 'A' Through 'B'; and Certificate of Service," filed on May 25, 2022 ("Companies Post-Hearing Reply").

II.

DISCUSSION

As a preliminary matter, the Commission would like to take this opportunity to again extend its appreciation to the Working Group for its continued support in addressing the five AOCs, which represent an opportunity to further strengthen the PBR Framework. The issues under consideration in this docket are both urgent and novel, and the Commission recognizes the commitment of time and resources by Working Group members. Through the collaborative and formal briefing phases, the Commission has benefited from the different perspectives of the Working Group and appreciates the various proposals and considerations offered for each AOC. The Commission is cognizant of the need to continue to evaluate the effectiveness of the PBR Framework and reiterates that it may re-visit any of the Framework's mechanisms if it appears that they are not operating as intended.[21]

Below, the Commission addresses each AOC in turn, including the Commission's determination as to the appropriate action(s) to address the AOC.

[21] See D&O 37507 at 185-188 and 203-205.

A.

AOC 1: Grid Reliability

The Commission approves the creation of a generation-based reliability PIM ("Generation Reliability PIM"). In so doing, the Commission recognizes that generation-based outages represent an area that is currently not captured in the existing transmission and distribution ("T&D") reliability PIM ("T&D Reliability PIM"), but is directly experienced by customers. As noted by several of the Parties during this phase of the proceeding, despite arising from different sources, from the customer's perspective, the distinction between a T&D-based interruption and a generation-based interruption has little meaning, and it should be incumbent on the utility to minimize interruptions from both sources. Accordingly, the Commission finds that the Generation Reliability PIM can serve as a valuable complement to the existing T&D Reliability PIM, and help incentivize the Companies to provide sufficiently reliable service to its customers.

This PIM shall be separate from the existing T&D Reliability PIM, but shall utilize a similar methodology and also be based on the SAIDI and SAIFI metrics, as reflected in the table below:

	SAIDI Generation	SAIFI Generation
Metric	Average duration of interruptions attributed to generation per consumer during the year	Average number of sustained interruptions caused by generation per consumer during the year
Target	Average historical performance for recent 10-year period: HECO: 2010-2019 HELCO: 2010-2019 MECO: 2009-2018 *Metrics and targets may utilize the modified IEEE 1366 methodology for normalizing Major Event Days, as approved in Docket No. 2019-0110.	Average historical performance for recent 10-year period: HECO: 2010-2019 HELCO: 2010-2019 MECO: 2009-2018 *Metrics and targets may utilize the modified IEEE 1366 methodology for normalizing Major Event Days, as approved in Docket No. 2019-0110.
Deadband	Average annual generation-caused outage duration between the target and the target plus 1 standard of deviation of the historical performance data.	Average annual generation-caused outage interruptions between the target and the target plus 1 standard deviation of the historical performance data.
Liveband	Average annual generation-caused outage duration between the target plus 1 standard deviation and the target plus 2 standard deviations of historical performance data.	Average annual generation-caused outage interruptions between the target plus 1 standard deviation and the target plus 2 standard deviations of historical performance data.

	SAIDI Generation	SAIFI Generation
Maximum Incentive	Penalty-only assessment of 3 basis points of shareholder-funded rate base.	Penalty-only assessment of 3 basis points for shareholder-funded rate base.

The Commission finds that establishing a separate PIM for generation-based service interruptions is appropriate under the circumstances. First, separate PIMs recognize that service interruptions from T&D may exhibit different characteristics than generation-based interruptions and allows for distinct measurement and incentives for each category of interruption. As noted by the Consumer Advocate, the Brattle Report submitted by the Companies indicates that "the magnitudes, duration, and frequency of generation outages are very different from those of T&D outages[,]" and "[c]ombining the two types of outages into a single composite PIM creates a significant risk that important differences between the two types of outages will be masked . . . ."[22] For example, a combined PIM may allow improvement in T&D reliability to mask declines in generation reliability, which would be undesirable, particularly given the increased importance of generation reliability as the Companies' begin to retire their fossil fuel units.

[22]CA FSOP at 7-8.

Relatedly, separate PIMs promote transparency between T&D-based interruptions and generation-based interruptions.[23] Having separate PIMs will make it more administratively efficient to make adjustments to either PIM to account for circumstances unique to T&D or generation-related interruptions.

Although the Companies allude to potential "perverse outcomes" of having separate penalties for T&D and generation-based interruptions,[24] the Commission does not find this persuasive. As noted above, T&D-based interruptions may be different than generation-based interruptions, so having separate PIMs ensures that the utility is incentivized to make sure the full spectrum of service interruption causes is addressed. Moreover, the Companies' own backcasting analysis indicates that between 2010 and 2020, there was only one year where two of the Companies would have incurred a penalty under both the T&D Reliability PIM and the Generation Reliability PIM, further undermining this concern.[25] Additionally, this PIM complements other PIMs in the PBR Framework that serve to

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[23]Cf. CA Response to PUC-CA-IR-27.a, filed on May 17, 2022 ("As has been discussed in workshops and filings, having separate measurements for generation and T&D allow the Commission to focus on specific performance areas that need attention, as compared to if combined metrics were used."); and Blue Planet FSOP at 2.

[24]See Companies FSOP at 44-45.

[25]See Companies Response to PUC-HECO-IR-94.d (Table 3), filed on May 17, 2022.

incentivize the Companies to ensure that efforts to maintain service reliability are balanced with other key initiatives, such as integrating increasing amounts of renewable energy and retiring fossil fuel units.

Further, keeping the Generation Reliability PIM separate from the T&D Reliability PIM will be more administratively efficient. Incorporating generation-based interruptions into the T&D Reliability PIM would require a potentially complex overhaul of the T&D Reliability PIM.[26] The Commission observes that by keeping the T&D Reliability PIM separate, no adjustments need to be made to that PIM at this time.

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[26]Cf. CA FSOP at 8 ("[The Companies'] proposed composite T&D and generation SAIDI/SAIFI metrics would be novel measures not known to be used in any other jurisdiction."); Blue Planet FSOP at 2 ("Adding new PIMs would also avoid the administrative burden and complexity of overhauling the existing PIMs, while retaining the administrative benefit of the longer-term continuity in the record and practice for the existing PIMs."); and CA Post-Hearing Brief at 6 (". . . having separate PIMs would not require revising existing and established practices and the need to thoroughly vet - now and in the future when questions may arise regarding a disparity of what is reported and what customers experience - a calculation that may include new normalizing and rebalancing adjustments to develop a combined SAIDI and SAIFI."). See also Companies FSOP, Exhibit A (Brattle Report) at pages 9-10 of 21 (noting that in the jurisdictions studied for the Brattle Report, "SAIDI and SAIFI is measured for network interruptions only (these jurisdictions have interconnected wholesale markets where generation reliability is not the responsibility of the utilities, and where interruptions caused by generation problems are extremely rare.").

There is comparatively little administrative burden in developing the standalone Generation Reliability PIM, as it largely incorporates the methodology from the T&D Reliability PIM, as reflected in the table, above, with which the Companies, Commission, and other Parties are already familiar. In addition, the Companies state that they already collect SAIDI and SAIFI information from generation-based outages.[27]

As noted in the table above, at this time, the Commission will allow the Generation Reliability PIM to adopt the same modified IEEE 1366 methodology for normalizing Major Event Days ("MEDs") as was approved for the T&D Reliability PIM in Docket No. 2019-0110.[28] At this time, the Commission finds this to be acceptable, as it should simplify implementation of the Generation Reliability PIM by keeping it similar to the existing T&D Reliability PIM.[29]

However, the Commission is aware that the reasons for normalizing MEDs from a T&D perspective may warrant different considerations than from a generation perspective. Furthermore,

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[27]See Companies FSOP at 46 (referring to the Companies' Annual Service Reliability Reports); and Companies Response to PUC-HECO-IR-89.k.ii, filed on April 22, 2022.

[28]See Docket No. 2019-0110, Decision and Order No. 37600, filed on February 2, 2021.

[29]Cf. Companies Responses to PUC-HECO-IR-89.i; and Consumer Advocate Response to PUC-CA-IR-27.c.

although normalization of MEDs may be a common practice for reporting reliability metrics, the Commission is concerned about the impacts of outages during MEDs to customers, who may experience significant interruptions to service during these major events. Accordingly, the Commission believes that consideration should be given to holistically evaluating service outages during MEDs, regardless if they are generation-based or T&D-based, as well as the system's resiliency during MEDs. To that end, the Commission instructs the Working Group to work on identifying and developing metrics to report on service reliability and resiliency of each island system to generation and T&D outages during major events. This metric(s) may be used to modify existing or develop a new PIM, as appropriate.

Consistent with the T&D Reliability PIM, the Commission finds that an asymmetrical design is appropriate. While the Companies have proposed a symmetrical design (i.e., one with rewards and penalties), the Commission does not find this persuasive. Reliable service is a fundamental aspect of the utility's obligations to customers and its operations. Accordingly, the Commission does not believe that rewards are appropriate for a "backstop" PIM that is intended to ensure that performance does not degrade relative to historic levels.[30]

The maximum incentive for the PIM for each Company shall be equivalent to three (3) basis points (i.e., 0.03% of shareholder-funded rate base). In arriving at this value, the Commission notes that on average, across the Companies and across SAIDI and SAIFI, the approximate proportion of outages attributable to T&D and generation is 88% and 12%, respectively. The ratio between the proportion for generation-based outages and the proportion for T&D-based outages (i.e., 12%/88% = 0.14) can be applied as a conversion factor to the maximum incentive of 20 basis points corresponding to the existing T&D reliability PIM[31] to yield 2.8 basis points,[32] rounded to 3 basis points.

The Commission declines to adopt the Consumer Advocate's suggestion of adding a "no-backsliding" provision to the target component of the T&D Reliability PIM and the Generation Reliability PIM.[33] While the Commission acknowledges the Consumer Advocate's

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[30]See Blue Planet FSOP at 3; and CA FSOP at 9. See also CA Post-Hearing Brief at 7 (citing Testimony of Isaac Moriwake, Hearing Day 1, April 26, 2022, at 32:24 - 32:31).

[31]The existing T&D reliability PIM has a maximum incentive of 20 basis points (i.e., 0.20% of shareholder-funded rate base) for each of SAIDI and SAIFI and for each of the Companies.

[32]20 * 0.14 = 2.8

[33]See CA PSOP at 6.

concern, it also notes that there may be unintended consequences to such a provision, such as inadvertently incentivizing the Companies to seek only incremental levels of improvement in reliability to avoid setting more difficult future targets.[34] Further, in light of the asymmetrical nature of these reliability PIMs, as well as the Commission's decision to deny the Companies' request to exclude generation outages from independent power producers ("IPPs") from the scope of the Grid Reliability PIM (discussed, infra), the Commission believes that a "no-backsliding" provision may not be appropriate during this period of transformation for the Companies.

The Commission also declines to adopt the Companies' proposal to exclude generation interruptions from IPPs from the PIM's scope.[35] The Commission acknowledges that the Companies will be adding new generation and energy storage resources over the remainder of the MRP, which they must integrate while maintaining reliability. However, the Commission does not believe that the addition of new resources solely justifies an automatic exemption for interruptions in service attributable to IPPs, nor an exemption for the first in-service year for an IPP facility. A key purpose

[34] See Ulupono Post-Hearing Brief at 15.

[35] See Companies Response to PUC-HECO-IR-90, filed on May 17, 2022, at 2.

of the Generation Reliability PIM is to ensure that generation reliability does not worsen as a result of changing resource portfolio dynamics.

Moreover, as reflected in the table above, the Generation Reliability PIM design features a deadband of one standard deviation from the target, which, when applied to historical generation reliability SAIDI and SAIFI metrics, reflects a wide range of performance under the PIM wherein the Companies would not be penalized. The Commission finds that this wide deadband helps mitigate the Companies' concern that IPP generation interruptions may cause the Companies to be unreasonably penalized. In addition, the Commission has calibrated the incentive levels for the Generation Reliability PIM to reflect the approximate proportion of generation-based interruptions to T&D-based interruptions. Put simply, the maximum penalties for the Generation Reliability PIMs are small and proportionate with the duration and frequency of outages caused by generation relative to interruptions attributable to T&D. Further, the Commission observes that there are a number of other upside PIMs under the PBR Framework (e.g., the RPS-A, as well as some of the new PIMs approved in this Decision and Order) that help balance the portfolio of incentives affecting integration of new renewable generation.

The Commission acknowledges that non-utility generators may contribute to generation-related interruption duration and frequency, which could impact each Company's generation SAIDI and SAIFI metrics to varying degrees. The Commission is also mindful that this dynamic may continue as renewable generation from IPPs increasingly come into service, and intends to monitor the contribution of IPP-caused interruptions on generation SAIDI and SAIFI going forward. Accordingly, the Companies shall report, if not already reported elsewhere, whether, and to what extent, generation-based service outage events are attributable to the utility or IPP-based resources.

Relatedly, the Commission declines to adopt the Companies' proposed modifications to the methodology for the T&D Reliability PIM at this time. This particular AOC was raised within the context of developing a mechanism to incentivize maintenance of adequate grid reliability associated with generation-based outages and constraints, not to fundamentally re-visit the existing T&D Reliability PIM.[36] While the Staff Proposal did contemplate limited examination of the T&D Reliability PIM, this referred specifically to the Consumer Advocate's proposal to consider whether an alternative method should be pursued to determine the PIM's target, and did

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[36]See Staff Proposal at 3.

not contemplate a wholesale re-examination of the PIM's design, including the weighting between SAIDI and SAIFI and the asymmetrical nature of the PIM's incentives.

Thus, although the Commission recognizes the Companies' efforts, the Commission declines to undertake a larger re-examination of the T&D Reliability PIM design at this time, and will instead focus on adopting the Generation Reliability PIM, as set forth above. That being said, as noted in prior decisions in this proceeding, the Working Group remains available as a venue to continue discussing modifications and improvements to the PBR Framework, and the Companies may seek to continue developing this proposal with the Working Group, if desired.

B.

AOC 2: Timely Retirement of Fossil Fuel Units

Upon considering the Parties' positions and the record in this proceeding, the Commission will not implement a PIM for this AOC at this time.[37] That being said, the Commission still believes that this matter requires urgent attention, given that "[t]hese retirements are a critical component of meeting the State's renewable energy goals and allowing customers to

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[37]Cf. Companies Post-Hearing Brief at 16; CA Post-Hearing Brief at 10-11; and Ulupono Post-Hearing Brief at 17-18.

experience the benefits of newly approved energy projects, which are not linked to volatile fossil fuel prices."[38] As such, the Commission instructs the Companies to prepare a comprehensive Fossil Fuel Retirement Report ("FF Retirement Report") for fossil fuel units on their respective systems. This Report will serve as both a plan to transparently set forth the Companies' efforts to timely retire key fossil fuel units and a means to hold the Companies accountable for unreasonable delays. In comparison to past grid planning activities, this FF Retirement Report is intended to focus exclusively on the steps necessary to safely retire fossil fuel units from the Companies' system, beginning with those units that have been identified for near-term retirement during the MRP. The Commission also recognizes the importance of long-term planning for additional retirements, but believes that such analysis is more appropriately addressed as part of the Integrated Grid Planning process. In this regard, the Commission has noted that "it is appropriate to evaluate the initial retirement assumptions during [the Grid Needs Assessment] process,"[39] and recognizes the Companies' intent to allow the

[38]Staff Proposal at 8-9.

[39]Docket No. 2018-0165, Order No. 38253, "Approving with Modifications, Hawaiian Electric's Revised Inputs and Assumptions," filed on March 3, 2022, at 65.

RESOLVE model to optimize the retirement schedules of thermal generating units as part of its High Fuel Price sensitivity.[40]

The FF Retirement Report shall provide specific details to implement the timely retirement of Waiau Units 3 & 4 on Oahu and the Kahului Power Plant on Maui, as well as any other fossil fuel units identified for potential retirement during this first MRP.[41] Specifically, the FF Retirement Report shall include, at a minimum, the following categories of information:

Overview

- The Companies shall identify every fossil fuel plant or unit that the Companies are currently intending to retire or deactivate and the respective target date.
- The Companies shall indicate whether the fossil fuel units that have been identified are intended to be retired or deactivated.
- The Companies shall identify the Company executive(s)/director(s) who is/are responsible for the successful and timely retirement or deactivation of each fossil fuel unit that has been identified.
- The Companies shall report on all supply- and demand-side projects or programs associated with

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[40]See Docket No. 2018-0165, Letter From: M. Asano To: Commission Re: Docket No. 2018-0165, Instituting a Proceeding to Investigate Integrated Grid Planning; Hawaiian Electric Revision to Update and Revised Inputs and Assumptions, filed on August 19, 2021, at 113.

[41]See e.g. Docket No. 2021-0024, Letter From: M. Asano To: Commission Re: Docket No. 2021-0024 - Opening a Proceeding to Review Hawaiian Electric's Interconnection Process and Transition Plans for Retirement of Fossil Fuel Power Plants; Generation Update for Maui Electric Company, Limited, filed on April 8, 2022 (noting that some units from the Ma'alaea power plant may be removed from service in 2025).

System Conditions (described below) that were completed in the past six months.

- The Companies shall list all governmental approvals for any of the identified projects or programs that the Companies require in the upcoming six months to maintain their current schedules.

System Conditions

- For each fossil fuel unit identified in the FF Retirement Report, the Companies shall identify all System Conditions (Capacity & Energy, T&D, or Other), including associated supply- and demand-side projects and programs, needed to be in place to successfully retire or deactivate that specific fossil fuel unit.

- The Companies shall identify the Company executive(s)/director(s) who is/are responsible for the successful and timely completion of each identified System Condition.

- The Companies shall identify all key milestones associated with each identified project or program, as well as the current progress associated with each milestone.

- The Companies shall provide an estimated date of completion for each identified project or program.

- The Companies shall identify any dates by which governmental approvals are needed, if necessary, to complete each identified project or program on schedule.

Supporting Analyses

- The Companies shall provide a critical path analysis for each identified project or program. This critical path analysis shall, at a minimum, identify all key milestones associated with each identified project or program, any interdependencies between those milestones, all known risks to the execution of each identified project or program, the likelihood of those risks, the contingency plans associated with any likely risks, and an estimated date of completion based on the critical path analysis.

  - If this critical path analysis includes tasks or milestones that are beyond the Companies' direct control, the Companies shall identify the entity responsible for the completion of that task or milestone, as well as a reasonable estimation of the timelines for those tasks or milestones.

- The Companies shall identify the Company executive(s)/director(s) who is/are responsible for the production and soundness of each analysis provided.

- The Companies shall provide copies of any analyses, planning or otherwise, that the Companies relied upon to determine the necessity of each identified project as a necessary System Condition.

  - The Companies shall identify the minimum amount of replacement resources that are needed to retire or deactivate each fossil fuel unit identified for retirement or deactivation. The minimum supply- and demand-side replacement resources should include required additions of capacity, energy, and ancillary services, as well as demand-side management and energy efficiency, to meet reliability and system planning criteria.

  - The Companies shall identify the total amount of replacement resources that the Companies are seeking to have in place prior to retiring or deactivating each fossil fuel unit identified for retirement or deactivation. The total replacement resources should include the Companies' proposed cost-effective portfolio of supply- and demand-side resources to replace capacity, energy, and ancillary services from each unit that will meet reliability and system planning criteria, including consideration of the portfolio's execution risk.

    - If the total replacement portfolio is different from the minimum replacement resources in any form, the Companies shall provide an explanation for the differences, including possible tradeoffs with customer costs, GHG emissions, compliance with environmental regulations, and portfolio execution risk.

    - The Companies' consideration of portfolio execution risk should include a review of all meaningful factors that could delay and/or affect costs of individual projects and programs, including interconnection, regulatory review, permitting, community acceptance, supply chain, and potential delays in project construction/commissioning or program implementation. The Companies shall explicitly review and consider these factors in proposing a portfolio that balances these risks to the retirement/deactivation schedule with total portfolio cost while meeting reliability and system planning criteria.

  - Where no analyses were conducted to support the inclusion of any identified project, the Companies shall provide an explanation as to why the identified Project is necessary.

The Companies shall provide regular updates on the implementation of the FF Retirement Report as follows:

- The Companies shall file this FF Retirement Report on a biannual basis, within ten business days of the end of Q1 and Q3 of the calendar year. The first FF Retirement Report shall be due within ten business day of the end of Q3 2022.

- In addition to its biannual reports, the Companies shall file this FF Retirement Report if instructed by the Commission.

- If any FF Retirement Report contains changes to any target dates, System Condition project or program milestones, or supporting analyses provided in the previously filed Report, the Companies shall identify every change made, as well as provide a detailed explanation for them.

- If circumstances change such that a project or program not previously contemplated in a previous FF Retirement Report is now warranted, the Companies may add the new project or program, along with a detailed explanation as to why this new project is now necessary.

The Commission emphasizes that the FF Retirement Report is not intended to force the Companies to retire or deactivate any fossil fuel unit by a single, inflexible target date. Rather, the FF Retirement Report is intended to provide the Commission with a comprehensive picture at a specific moment in time of all the supporting pieces that need to be in place to facilitate the retirement or deactivation of a fossil fuel unit, the interdependencies within and between those pieces, and the Companies' current plans and execution of those plans in furtherance of timely retiring or deactivating a fossil fuel unit.

Failure to comply with this FF Retirement Report, or provide reasonable justifications for setbacks in project schedules or target dates, may result in further Commission action including, but not limited to, an investigation and the assessment of penalties. Penalties may include, but are not limited to, disallowance of recovery for O&M and fuel costs beyond certain milestone dates if the Companies are not making reasonable progress towards plant retirement and the integration of new resources.

The Commission believes this approach balances the urgency behind ensuring that the Companies are implementing the necessary steps to timely retire the fossil fuel units with the concerns raised by the Parties.

Concomitantly, given the Commission's decision to implement an SSM focused on the Companies' non-ARA costs (discussed infra), the Commission does not believe it is necessary to adopt the Companies' proposed fossil fuel intensity PIM.[42]

C.

AOC 3: Interconnection of Large-Scale Renewable Projects

Upon considering the Parties' positions and the record in this phase of the proceeding, the Commission approves the creation of an IRS PIM ("IRS PIM"). This PIM shall incentivize the Companies to timely complete this critical portion of the interconnection process, thereby supporting the overall goal of timely interconnecting large-scale renewable energy projects onto the Companies' system. The design for the IRS PIM is as follows:

Metric	Count of months between final model checkout and delivery of IRS results to the developer.
Target	10 months
Deadband	Asymmetrical, two-month deadband following the 10-month target, where penalties begin when IRS completion takes longer than 12 months.
Incentive	Penalties Penalty = x% * [project NEP[43] or equivalent estimate of first year MWh] * ($20/MWh output)

[42]See Companies FSOP at 110-111.

[43]"NEP" = "net energy potential."

Where x =

<1 month beyond deadband = 2%

Between 1 month and <2 months beyond deadband = 4%

Between 2 months and <3 months beyond the deadband = 6%

Between 3 months and <4 months beyond the deadband = 8%

Between 4 months and <5 months beyond the deadband = 10%

Between 5 months and <6 months beyond the deadband = 12%

Between 6 months and <7 months beyond the deadband = 14%

Between 7 months and <8 months beyond the deadband = 16%

Between 8 months and <9 months beyond the deadband = 18%

9 months or greater beyond the deadband = 20%

<u>Rewards</u>

Reward = y% * [project NEP or equivalent estimate for first year MWh output] * ($20/MWh)

Where y =

<1 months before target = 4%

Between 1 and <2 months before target = 8%

Between 2 and <3 months before target = 12%

Between 3 and <4 months before target = 16%

4 months or greater before target = 20%

*Penalties and rewards are not cumulative.

Contingencies	▪ The Companies may seek review and potential adjustment of this PIM, on a case-by-case basis, for circumstances outside of the Companies' control that affect the IRS process (e.g., re-studies requested by developers), or when a project ultimately achieves commercial operations by its Guaranteed Commercial Operations Date ("GCOD").

In arriving at this PIM structure, the Commission has taken into consideration the complexities of the interconnection process, including the potential for unforeseen events, and focused on a portion of the process over which the Companies exert a large amount of direct control. To this end, the Commission has decided to not proceed with a more comprehensive PIM structure previously vetted by Parties, which would have included an additional incentive structure for project completion.[44]

In light of the more focused nature of this PIM, the Commission has also widened the deadband, as recommended by some Parties.[45] Additionally, due to the removal of the back-end reward structure from the PIM design, the Commission has modified

[44] See PUC-Parties-IR-17, issued on May 12, 2022.

[45] See e.g. Companies Post-Hearing Reply at 10 (suggesting that penalties should start at months 12 and 13); and Ulupono Response to PUC-Parties-IR-17.d, filed on May 19, 2022, at 5 (voicing support for a two-month deadband).

the reward schedule for this PIM so that reward and penalty potentials are more symmetrical.

As noted above, the incentive is based on a project's NEP, which is a contractual feature of the Renewable Dispatchable Generation PPAs ("RDG PPAs") that were used in Stages 1 and 2 of the Companies' competitive solicitation for renewable energy projects.[46] The Commission has incorporated a fixed incentive level equal to the RPS-A incentive as a component of the IRS PIM to avoid the shortcomings of a benchmark approach highlighted earlier in the development of this PIM.[47] While the Commission would like to see this PIM's scope expanded to include all IPP projects under development, it recognizes the complexities with developing an appropriate $/MW value that could be used for non-RDG PPA projects and that would be comparable to the current RPS-A incentive value. As a result, the Commission will approve the IRS PIM with an NEP-based incentive, but instructs the Working Group to consider and propose alternative methodologies for calculating an incentive for non-RDG PPA projects.

While the ultimate objective is to ensure that new renewable energy projects are brought online in a timely manner,

[46]See generally Docket No. 2017-0352.

[47]See Companies Response to PUC-Parties-IR-16.c, filed on April 25, 2022, at 11-12.

the Commission recognizes the unique circumstances currently complicating project interconnection, including supply chain disruptions associated with the COVID-19 pandemic and the ongoing conflict in Ukraine. Accordingly, the Commission has chosen to focus on a portion of the project development schedule that is more squarely within the utility's control and less affected by external factors.

The Commission acknowledges several concerns raised by some of the Parties, but does not find them persuasive. First, the Commission does not believe that reliance on the RPS-A PIM, alone, sufficiently addresses this AOC.[48] The RPS-A broadly incentivizes the Companies at a portfolio level, influencing planning decisions such as fossil fuel retirements and integration of distributed resources in addition to utility-scale renewable generation. As such, the RPS-A only indirectly influences the specific behaviors necessary to more quickly interconnect large renewable energy projects. Rather than act as a substitute, the RPS-A is a complement to this more targeted PIM, helping to incentivize the overall completion of the project following completion of the IRS process.

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[48]See Companies Post-Hearing Reply at 9-10; CA Post-Hearing Brief at 15-16; and Ulupono Post-Hearing Brief at 21.

Second, the Companies' efforts to improve the interconnection process are not a basis for delaying a PIM in this area, particularly given the Commission's ongoing concern with project delays associated with interconnection. Prior to the current supply chain disruptions associated with the COVID-19 pandemic, many of the RFP Stage 1 projects encountered significant interconnection process delays which pushed back the estimated GCODs by an average of 14.5 months.[49] This resulted in a number

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[49]See Docket No. 2018-0430, Letter From: K. Katsura To: Commission Re: Docket No. 2018-0430 - For Approval of a Power Purchase Agreement for Renewable Dispatchable Generation with AES Waikoloa Solar, LLC - Interconnection Requirements Amendment; Request for Approval of Overhead Line, filed on August 31, 2020, at 9 (indicating an updated GCOD date that reflects an approximately 15-month delay); Docket No. 2018-0431, Letter From: K. Katsura To: Commission Re: Docket No. 2018-0431 - For Approval of a Power Purchase Agreement for Renewable Dispatchable Generation with Ho`ohana Solar 1, LLC; Interconnection Requirements Amendment; Request for Approval of Overhead Line, filed on February 26, 2021, at 14 (indicating an updated GCOD date that reflects an approximately 20-month delay); Docket No. 2018-0432, Letter From: K. Katsura To: Commission Re: Docket No. 2018-0432 - For Approval of a Power Purchase Agreement for Renewable Dispatchable Generation with Hale Kuawehi Solar LLC - Interconnection Requirements Amendment; Request for Approval of Overhead Line, filed on September 4, 2020, at 9 (indicating an updated GCOD that reflects an approximately 5-month delay); Docket No. 2018-0433, Letter From: K. Katsura To: Commission Re: Docket No. 2018-0433 - For Approval of a Power Purchase Agreement for Renewable Dispatchable Generation with Paeahu Solar, LLC - Interconnection Requirements Amendment; Request for Approval of Overhead Line, filed on October 29, 2020, at 10 (indicating an updated GCOD that reflects an approximately 16-month delay); Docket No. 2018-0434, Letter From: K. Katsura To: Commission Re: Docket No. 2018-0434 - For Approval of a Power Purchase Agreement for Renewable Dispatchable Generation with Mililani I Solar, LLC - Interconnection Requirements Amendment, filed on

of Commission actions, including an investigation in Docket No. 2021-0024, in which the Commission noted, inter alia, "that current interconnection processes are causing unnecessary delays and increasing project costs," and that "[t]he opacity of [the Companies'] current interconnection processes also contributes to the challenges encountered by project developers and this Commission . . . ."[50]

While the Commission is encouraged to learn that the Companies have taken the initiative to implement improvements to the interconnection processes, the Commission finds that the urgency surrounding this situation warrants parallel Commission

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September 18, 2020, at 6 (indicating an updated GCOD that reflects an approximately 10-month delay); Docket No. 2018-0435, Letter From: K. Katsura To: Commission Re: Docket No. 2018-0435 - For Approval of a Power Purchase Agreement for Renewable Dispatchable Generation with Waiawa Solar Power LLC - Interconnection Requirements Amendment; Request for Approval of Overhead and Underground Line, filed on October 9, 2020, at 10 (indicting an updated GCOD that reflects an approximately 11-month delay); Docket No. 2018-0436, Letter From: K. Katsura To: Commission Re: Docket No. 2018-0436 - For Approval of a Power Purchase Agreement for Renewable Dispatchable Generation with AES Kuihelani Solar, LLC - Interconnection Requirements Amendment; Request for Approval of Overhead Line, filed on February 16, 2021, at 10 (indicating an updated GCOD that reflects an approximately 27-month delay); and Docket No. 2019-0050, Letter From: K. Katsura To: Commission Re: Docket No. 2019-0050 - For Approval of a Power Purchase Agreement for Renewable Dispatchable Generation with AES West Oahu Solar, LLC - Interconnection Requirements Amendment; Request for Approval of Overhead Line, filed on September 8, 2020, at 8 (indicating an updated GCOD that reflects an approximately 11-month delay).

[50]Docket No. 2021-0204, Order No. 37624, "Opening the Docket," filed on February 11, 2021, at 3.

action to address this issue, including the implementation of the IRS PIM.

Third, the Commission does not believe that SB2474, if signed into law,[51] warrants delaying this PIM. As noted above, there is an urgency with implementing improvements to the interconnection process, as delays have pushed the commercial operations date for a number of projects months, if not years, beyond their originally anticipated date. The Commission has been investigating this matter, both in this proceeding, as well as through related proceedings, such as Docket No. 2021-0024, well before SB2474 was introduced. SB2474, if approved, would result in a study that may contribute to this base of knowledge, but is not a reason to delay addressing this AOC. To the extent SB2474 results in study findings that shed new insight into areas of improvement to the interconnection process, it can be taken up by the Working Group at that time.

Fourth, while the IRS process is only a part of the overall interconnection process, it nonetheless plays a critical role that enables the subsequent key stages of project development. Moreover, it is one of the few areas in the interconnection process

[51]SB2474 is a bill that would necessitate, among other statutory requirements, a study and report on the Companies' interconnection process and the reasonableness of its associated timelines.

over which the Companies currently exercise a large degree of control.

Finally, in response to the Companies' concerns, the Commission has adopted a number of design modifications. These include a symmetrical incentive structure for this PIM's design, which will recognize exemplary efforts by the Companies in this area, as well as safeguards for the Companies, such as the inclusion of an asymmetrical deadband before penalties are assessed, as well as the opportunity to seek review in the event circumstances outside of the Companies' control impact the IRS process. The Commission also intends to hire an Independent Engineer to oversee the interconnection process in the Companies' upcoming Stage 3 Request for Proposals. This entity would add oversight on the implementation of the IRS PIM and provide due process, as requested by the Companies.[52]

D.

AOC 4: Cost Control for Fossil Fuel, Purchased Power, and Non-ARA Costs

As noted in the Staff Proposal, the PBR Framework's primary cost control mechanisms, the MRP and Annual Revenue Adjustment Mechanism ("ARA"), are focused on the Companies' base

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[52]See Companies Post-Hearing Brief at 20.

costs,[53] which account for roughly half of the Companies' costs. Other operating costs include fuel, purchased, power, and certain capital costs are recovered "outside" of the ARA.[54] Fuel and purchased power costs are recovered directly from customers via surcharges (i.e., the Energy Cost Recovery Clause ("ECRC") and the Purchased Power Adjustment Clause ("PPAC")), while certain capital costs for approved projects are recovered through the EPRM via annual adjustments to Target Revenue above the prescribed ARA formula.

The issue of addressing these non-ARA costs has been previously broached in earlier phases of this proceeding,[55] and the Staff Proposal built upon these earlier efforts in offering for consideration by the Working Group a "Conjunctive Shared Savings Mechanism" ("Candidate CSSM") to addresses this AOC.[56] During the course of the Working Group process and in Parties' filings, the merits of the Candidate CSSM were examined in detail, with the Parties expressing various concerns and proposing changes, but generally supporting or accepting the Candidate CSSM.

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[53]The base costs recovered through the ARA reflect revenue requirements excluding fuel expense, purchased power expense, revenue taxes and other costs recovered through surcharges.

[54]See Staff Proposal at 16.

[55]See PUC-Parties-IR-1 through -3, filed on July 24, 2020.

[56]See Staff Report, Appendix B

Taking this into consideration, and in line with the PBR Outcome of "cost control,"[57] the Commission finds that additional mechanisms to address these non-ARA costs are warranted to ensure that the Companies are incentivized to control costs across all operations, and not just those areas that fall under the ARA.

Consistent with the above, the Commission approves a collective SSM ("Collective Shared Savings Mechanism" or "CSSM") to incentivize improved control over non-ARA-related costs. The CSSM is similar in fundamental respects to the Candidate CSSM presented in the Staff Report, but includes several differing features based on proposals and discussion in the Working Group process and in the Parties' PSOPs and FSOPs. Under the CSSM, the Companies will be allowed to retain a portion of any reduction in the sum of fuel, purchased power, and MPIR/EPRM[58] costs for each future performance year ("Performance Year") in comparison to a base year ("Base Year") target. This provides a straightforward incentive for the Companies to reduce overall costs in these areas, with the assurance that any reward to the Companies would be

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[57]See Decision and Order No. 36326 at 7, filed on May 23, 2019.

[58]The Major Project Interim Recovery Mechanism ("MPIR") was the predecessor to the EPRM. Although the MPIR is no longer available, projects approved for MPIR recovery are within the scope of the CSSM.

directly associated with a corresponding reduction in customers' bills. The characteristics and details of the CSSM are explained below.

CSSM Performance Metric ("CSSM Performance Metric"). The CSSM shall be applicable to revenues arising from fuel expense for utility generation, purchased energy and purchased capacity costs, costs of new contractual resources acquired through RFPs and PPAs, and costs of new utility projects not funded with revenues governed by the ARA formula, which are collectively recovered through the ECRC, PPAC, and MPIR/EPRM. The CSSM Performance Metric is the sum of the ECRC, PPAC, and MPIR/EPRM revenues, excluding revenue taxes, measured each calendar year, which is equivalent to a Performance Year.

CSSM Target ("CSSM Target"). The CSSM Target represents a calculated amount of collective ECRC, PPAC, and EPRM revenue against which the Performance Year Metric is compared. As noted in more detail below, the CSSM Target is calculated for a Base Year with appropriate adjustments for inflation and Performance Year fuel prices and system generation.

CSSM Performance Year Savings ("CSSM Performance Year Savings"). The CSSM Performance Year Savings is the amount that the CSSM Performance Metric (sum of ECRC, PPAC and MPIR/EPRM revenue in the Performance Year) is less than the CSSM Target. This represents the amount of savings achieved by the Companies compared to the Base Year, after adjustment for inflation and Performance Year fuel prices and system generation, as provided below.

CSSM Incentive Award. The CSSM annual award to the utility is a portion ("Sharing Percentage") of the CSSM Performance Year Savings. The CSSM only provides an award if there are positive CSSM Performance Year Savings; the CSSM is never a penalty to the utility.[59]

Basic CSSM Formulas. The basic CSSM provisions as expressed above are represented in the following general formulas. These formulas, except for some terminology, are essentially identical to the formulas included in the Candidate CSSM presented in the Staff Report.[60] More detailed formulas are provided further below.

$$\boldsymbol{CSSM\ Performance\ Metric = \ EPRM + PPAC + ECRC\ \ [Performance\ Year]}$$

$$\boldsymbol{CSSM\ Target = \ EPRM + PPAC + ECRC\ \ [Base\ Year; fuel\ price, inflation, gen.\ adjusted]}$$

$$\boldsymbol{CSSM\ Incentive\ Award = Sharing\ \% \ \times (CSSM\ Target - CSSM\ Performance\ Metric)}$$

Adjustment for Fuel Price. The ECRC component of the CSSM Performance Metric is subject to strong variation in fuel prices. The CSSM is intended to insulate the determination of

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[59]As discussed, infra, the Commission declines to adopt the Consumer Advocate's recommendation to adopt a symmetrical design for the CSSM.

[60]See Staff Report, Appendix B at 4. Note that "EPRM" includes its predecessor, the MPIR mechanism.

awards, to the extent possible, from the potentially overpowering effects of short-term fuel price volatility which is not in the Companies' control. To address this, the ECRC component of the CSSM Target will be quantified using the same fuel prices as are used in the Performance Year ECRC component of the CSSM Performance Metric. Using the price of fuels in the Performance Year to calculate the CSSM Target is intended to nullify the effects of price volatility and account for inflation.

For some IPP contracts, the price charged to the utility may depend explicitly on fuel price. For these IPPs, the CSSM Target ECRC component should be adjusted as indicated by the IPP contract price formula to reflect Performance Year fuel price.

As noted by the Companies in the Working Group discussions, some fuel types used in the Base Year and included in the CSSM Target may not continue to be used in future Performance Years. For these fuel types, proxy prices should be established based on proportional price changes in a most-similar fuel. Where fuel prices in the Base Year are determined by contractual formulas based on an index that remains available in the Performance Year, fuel prices can be directly inferred.

Adjustment for Inflation. The CSSM will incorporate adjustments for inflation. Parameters, as appropriate, will be evaluated on a "real dollar" (i.e., inflation-adjusted) basis.

This is consistent with the ARA component of the PBR Framework, wherein the utility is rewarded for reducing rates below the rate of inflation. Except as noted specifically below, the CSSM Target will be adjusted for recorded inflation between the Base Year and Performance Year.

Inflation should be indexed on the Gross Domestic Product Price Index ("GDPPI"), but unlike the ARA provision and previous Revenue Adjustment Mechanism provisions, the CSSM does not require forward-looking estimates of GDPPI, therefore actual historical GDPPI change can be applied as the index for inflation adjustments.

As clarified in the discussions in the Working Group, components of the ECRC that are adjusted based on fuel price do not need to be explicitly escalated for inflation since fuel prices implicitly include inflation effects.

The Commission notes that in the modeling analyses provided by the Companies to verify the functioning of the CSSM,[61] Base Year PPAC amounts were not adjusted for inflation in

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[61]See discussion below regarding initial and revised sets of illustrative calculations of the CSSM provided in the Working Group process (provided December 17, 2021 and January 7, 2022, respectively), and model analyses provided in the Companies' Response to PUC-HECO-IR-83, filed on April 4, 2022.

determining the CSSM Target in later years.[62] For purposes of initial implementation of the CSSM, the Commission will accept the Companies' suggested convention in this regard; the PPAC will not be adjusted for inflation to determine the CSSM target, except for components or contracts that already explicitly include escalation factors, in which case the contractual escalation factors will be used.

Adjustment for System Generation. The amount of system generation can be reasonably expected to change over the period the CSSM is applied, especially when considered in the long term. For example, utility and IPP Generation may be reduced by customer efficiency measures or customer generation, or system generation needs may increase with electrification of transportation. The CSSM Performance Awards should not be perturbed by potentially large decreases or increases in system generation requirements, as the Companies should be rewarded for providing whatever sales and demand requirements may occur in the most economical manner.

As outlined in the Candidate CSSM presented in the Staff Report, in order to provide meaningful comparison of Performance Year parameters to the Base Year CSSM Target, the cost

[62]The only adjustment for inflation for the PPAC in the Companies' modeling analysis seems to be for specific fixed and variable operations and maintenance expense for the AES unit on HECO's system.

components are denominated by the amount of Company and IPP generation ("System Generation").[63] This effectively puts the comparison of the CSSM Performance Metric and the CSSM Target on a "rates" basis.[64] This appropriately adjusts for the gross impacts of changes in generation needs while preserving incentives for the Companies to optimize and improve generation efficiency, optimize IPP versus company generation fractions, and reduce transformation and station losses.[65]

The Commission notes that in determining the CSSM Target in the modeling analyses provided by the Companies to verify the functioning of the CSSM,[66] some elements of the PPAC were categorized as fixed and were not adjusted for system generation, and some elements were categorized as variable and were adjusted for system generation. In the process provided below for reviewing the tariffs and calculation worksheets, the Companies shall propose and explain appropriate methods for adjustments of PPAC elements for system generation.

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[63]For purposes of the CSSM, System Generation refers to net-to-system contributions of Company and IPP generation. This excludes customer generation, which is not a component of the ECRC, PPAC or MPIR/EPRM revenue.

[64]Staff Report Appendix B at 2.

[65]Staff Report Appendix B at 3.

[66]See spreadsheet model analyses provided in response to PUC-HECO-IR-83.

The implementation of the CSSM approved herein differs in one respect from the Candidate CSSM regarding the adjustment of the EPRM component for System Generation. In the Candidate CSSM, the EPRM component was not included with the PPAC and ECRC components adjusted for system generation, but was included as a separate unadjusted component. In the CSSM approved herein, as reflected in the detailed formulas, the EPRM is included with the PPAC and ECRC in the adjustment for system generation.

ECRC Heat Rate, Deadband and Fuel Price Risk Sharing Adjustments. Both the CSSM Target and Performance Year ECRC costs should be evaluated using the same heat rate deadband provisions as those used in the existing implementation of the ECRC. The Commission notes that this should simplify the documentation and verification of CSSM metrics since these should match or be feasibly compared to the filed annual ECRC reconciliations.

The fuel price risk sharing provisions in the existing implementation of the ECRC should not be included in the determination of the CSSM Target or CSSM Performance Metric. The Commission notes that this will not interfere with the current functioning of the fuel price risk-sharing mechanism and is consistent with insulating the amount of the CSSM Incentive Awards from fuel price volatility that is not in the control of the utility.

Inclusion of EPRM in the CSSM. The Consumer Advocate has recommended that EPRM should be excluded from the CSSM.[67] In support, the Consumer Advocate raises concerns that the CSSM could discourage the Companies from investments in transformative and beneficial major projects.[68] The Commission does not agree with the Consumer Advocate's recommendation. The Commission notes first that the magnitude of the Sharing Percentage in the CSSM is intended to partially offset the existing earnings incentives (capital bias) inherent in EPRM recovery by providing earnings opportunities by reducing revenue requirements; the CSSM does not remove or reduce existing earnings opportunities. The Companies maintain the undiminished opportunity to earn a fair return on capital invested in approved projects through the EPRM.

Second, the Consumer Advocate's position to exclude the EPRM appears to be linked to its related position that the CSSM should be "symmetrical" and include penalties as well as rewards for CSSM performance, in which case the Consumer Advocate's concern regarding undue disincentives to implement transformative and/or desirable projects would be more germane. Since the Commission declines to make the CSSM symmetrical at this time, the Commission rejects the suggestion to exclude the EPRM component on this basis.

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[67] See CA Post-Hearing Reply at 15.

[68] See CA Post-Hearing Reply at 15-16.

Detailed CSSM Formulas. The CSSM provisions as expressed above are represented in the following detailed formulas. These formulas are similar to the formulas included in the Candidate CSSM presented in the Staff Report with adjustments to reflect the terminology and details discussed above.[69] Note that the term "EPRM" refers both to the EPRM and its predecessor mechanism, the MPIR.

$$\boldsymbol{CSSM\ Target_n = \left(\left(\frac{EPRM_0 + PPAC_0 + Target\ ECRC_n}{System\ Generation_0}\right) \times System\ Generation_n\right)}$$

[Target is Adjusted to the Performance Year for Inflation]

$$\boldsymbol{Target\ ECRC_n = IPP\ Energy\ Cost_0 + \sum(Fuel\ Prices_n \times Heat\ Rates_0 \times Utility\ Generation_0)}$$

Where:

$$EPRM_0 = Base\ Year\ Annual\ EPRM\ Adjustment$$

"EPRM" includes predecessor MPIR Adjustments.

$$PPAC_0 = Base\ Year\ PPAC\ Amount$$

$$System\ Generation = IPP\ Generation + Utility\ Generation$$

$$System\ Generation_0 = Base\ Year\ System\ Generation$$

$$System\ Generation_n = Performance\ Year\ System\ Generation$$

$$IPP\ Energy\ Cost_0 = Base\ Year\ ECRC\ Purchased\ Energy\ Cost, fuel\ price\ adjusted$$

$$Fuel\ Prices_n = Performance\ Year\ ECRC\ Fuel\ Prices\ by\ Fuel\ Type$$

$$Heat\ Rates_0 = Base\ Year\ ECRC\ Efficiency\ Factors\ by\ Fuel\ Type$$

$$Utility\ Genertion_0 = Base\ Year\ Utility\ Generation\ by\ Fuel\ Type$$

$$\boldsymbol{CSSM\ Performance\ Metric_n = EPRM_n + PPAC_n + Metric\ ECRC_n}$$

$$\boldsymbol{Metric\ ECRC_n = IPP\ Energy\ Cost_n + \sum(Fuel\ Prices_n \times Heat\ Rates_n \times Utility\ Generation_n)}$$

[69] Staff Report, Appendix B at 5.

Where:

$$EPRM_n = Performance\ Year\ Annual\ EPRM\ Adjustment$$

"EPRM" includes predecessor MPIR Adjustments.

$$PPAC_n = Performance\ Year\ PPAC\ Amount$$

$$IPP\ Energy\ Cost_n = Performance\ Year\ ECRC\ Purchased\ Energy\ Cost$$

$$Fuel\ Prices_n = Performance\ Year\ ECRC\ Fuel\ Prices\ by\ Fuel\ Type$$

$$Heat\ Rates_n = Performance\ Year\ ECRC\ Efficiency\ Factors\ by\ Fuel\ Type$$

$$Utility\ Genertion_n = Performance\ Year\ Utility\ Generation\ by\ Fuel\ Type$$

Determination of the Base Year. The selection of an appropriate base year for the determination of the CSSM Target was an issue discussed and examined by the Parties in the Working Group Technical Conferences and through IRs. The Companies provided several spreadsheet models with historical backcasts and projected CSSM scenarios, which were helpful in verifying mutual understanding of the CSSM formulas and identifying and clarifying necessary details, including the Base Year.[70]

[70]The Companies provided initial and revised sets of illustrative calculations of the CSSM in the Working Group process (provided December 17, 2021 and January 7, 2022, respectively). Further model analyses were provided in response to Commission IRs. See Companies Response to PUC-HECO-IR-83. The Companies model analyses as provided assume a 2021 Base Year but allow examination of alternate years as the Base Year. See also Companies Response to CA/HECO-IR-10.a, filed on March 4, 2022.

The Companies propose the 2021 calendar year as the Base Year for the CSSM, noting that 2021 is the most recent year for which complete information is available.[71]

In reviewing the modeling analyses and considering the Companies' recommendation, the Commission finds that the calendar 2021 year is appropriate as the Base Year for the initial implementation of the CSSM. In so doing, the Commission notes that no Parties have proposed a specific Base Year other than the 2021 calendar year proposed by the Companies, 2021 represents the most recent year for which full-year information is available, and 2021 reflects reasonably normal operations.

Determination of the Sharing Percentage. The CSSM incorporates a Sharing Percentage that determines the amount of the annual CSSM Performance Year Savings that will be awarded to the utility as the CSSM Incentive. In the Staff Report and in presentations to the Working Group, the Commission included a sharing percentage of 30% as a proxy example in the expository CSSM equations but did not recommend a specific Sharing Percentage. In presentations to the Working Group and in IRs, the Commission invited the Parties to examine and propose an appropriate

[71] See Companies FSOP at 108 (citing Companies Response to PUC-HECO-IR-83.d).

Sharing Percentage and provide related supporting analysis.[72] The amount of the Sharing Percentage and associated incentives were also explored by the Parties' IRs.[73]

In consideration of the CSSM analyses provided by the Companies and the arguments and information presented by the Parties,[74] the Commission will set the Sharing Percentage at 20% for the initial implementation of the CSSM. This percentage is consistent with the sharing percentages implemented in several prior project-specific SSMs, and should provide an effective incentive to the Companies to control fuel, purchased power and investment costs, while maintaining the bulk of net performance savings for the benefit of customers. The Sharing Percentage is intended to at least partially offset existing capital bias associated with EPRM investments without discouraging necessary and transformative investments in exceptional projects.

The Commission notes that the 20% Sharing Percentage is the same as the percentage share allocated to each Company in the first "tier" of savings in the Companies' proposal,

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[72]See Consumer Advocate Responses to PUC-CA-IR-23, filed on March 23, 2022; and Companies Responses to PUC-HECO-IR-83 k., PUC-HECO-IR-84 and PUC-HECO-IR-85, filed on April 4, 2022.

[73]See Companies Response to CA/HECO-IR-10 parts b. and c.; and Ulupono Responses to CA/Ulupono-IR-6 and HECO/Ulupono-IR-13, filed on March 4, 2022.

[74]See Companies Responses to PUC-HECO-IR-83, PUC-HECO-IR-84, and PUC-HECO-IR-85.

as explained below. In this respect the Commission accepts the Companies' suggested sharing percentage for an initial tier of CSSM Performance Year Savings.

The Companies proposed a tiered allocation of CSSM performance year Savings. For an initial amount of performance year CSSM savings ($5 million for HECO and $1 million, each, for HELCO and MECO), savings would be allocated 20% to the Company, 20% to an LMI assistance fund, with the remaining 60% benefiting all customers. Beyond the initial amounts of CSSM savings for each Company, savings would be allocated 5% to the Company, 30% to an LMI assistance fund, with 65% benefiting all customers.[75] A specific Sharing Percentage was not proposed by any other Party.

The Commission finds that this tiered approach has merit. Similar to the implementation of the Earnings Sharing Mechanism of the PBR Framework, a tiered approach provides diminishing returns without abruptly truncating incentives when a hard "cap" is reached. This allows for effective limitation of CSSM awards that may become excessive without entirely removing marginal incentives should the Companies' performance become exemplary.

Further, the Commission finds that the Companies' proposal to allocate a portion of the CSSM Performance Year Savings

[75]See Companies PSOP at 62-63; and FSOP at 108.

to an LMI assistance fund has merit. However, recognizing that the nature and necessary details regarding the implementation of the proposed LMI Assistance Fund have not been determined, the Commission directs the Working Group to evaluate and refine the Companies' LMI Assistance Fund proposal for consideration by the Commission, including the appropriate allocation to the LMI Assistance Fund, sufficient detail regarding how the fund would work, who should administer the fund, how funds would be held and managed, how the funds would be used, and what criteria would determine who qualifies as an eligible benefiting customer.

The Working Group shall submit its proposal(s) to the Commission by the end of 2022 for the Commission's review. Based on the Working Group's proposal(s), the Commission may modify the allocation of the CSSM savings, as well as approve details regarding an LMI Assistance Fund.

As a result, for the initial implementation of the CSSM, the sharing allocation of CSSM savings shall be in accordance with the Companies' proposal, but modified as follows:

Company	CSSM Savings Amount	CSSM Savings Allocation
HECO	≤ $5 million	20% (remainder to customers)
	> $5 million	5% (remainder to customers)
HELCO	≤ $1 million	20% (remainder to customers)
	> $1million	5% (remainder to customers)
MECO	≤ $1 million	20% (remainder to customers
	> $1 million	5% (remainder to customers)

As noted above, this savings allocation may be modified by the Commission pending the outcome of the Working Group's discussion of the Companies' proposed LMI Assistance Fund.

General considerations. New utility projects or contracts that reduce ECRC and/or PPAC annual expenses by more than the new project annual costs would increase the CSSM incentive awards. The opportunity for acquisition and utilization of new renewable generation projects is expected to be a main driver of reductions in customer rates in the next few years, and would be a main driver of net CSSM benefits and incentive awards.

Because the CSSM awards would be based on net benefits, including consideration of new project costs, the CSSM would provide persistent incentives to control costs. The cost control incentives would apply to any efficiencies the Companies can attain through good planning, resource acquisition and system operation.

Addressing structural capital bias was one of the principal objectives identified by the Commission, explicitly stressed in its guidance to the Parties in the PBR working group process. One unique feature of the CSSM is that it is the only mechanism identified that addresses structural capital bias directly.[76] The CSSM would also provide marginal incentives regarding the acquisition of contracted resources, when cost-effective compared to utility-owned resources, to balance existing bias for rate-basing new assets.

Further, the Commission notes that this concept has been vetted and refined in response to feedback from the Working Group and that there is general support for the CSSM. Many of the concerns and considerations raised by the Parties have been taken into account in developing the CSSM's design (e.g., effect of inflation, normalization of fuel costs, etc.).

Although the Consumer Advocate opposes implementation of the CSSM at this time, the Commission does not find these concerns persuasive. As noted above, the Commission observes that at least some of the Consumer Advocate's opposition appears to be rooted in

[76]Some of the Parties argue that allowing the EPRM mechanism to recover O&M expense projects as well as capital projects addresses capital bias. This may reduce the extent to which the EPRM mechanism itself creates capital bias, but it is well recognized that capital bias is a structural issue more fundamental than the bias created by the EPRM mechanism.

its position that the CSSM should be symmetrical; that is, feature both rewards and penalties based on a Performance Year's costs compared to the Base Year. However, upon consideration of the record, the Commission declines to make the CSSM symmetrical. One of the attractive features of the CSSM is its straightforward nature - i.e., rewards under the CSSM are directly linked to decreases in the Companies' spending. The Commission believes that this creates a powerful incentive, and does not believe that introducing a penalty component is appropriate for this initial version of the CSSM, as it may complicate the SSM design, as well as distract the Companies from exploring more creative and efficient means at reducing non-ARA costs.

Furthermore, while the Commission appreciates the Consumer Advocate's desire to spend additional time evaluating the PBR Framework before implementing new measures,[77] the Commission believes that more urgent action is warranted, considering that these particular cost components are not otherwise addressed by the existing PBR Framework.

Draft Calculation Worksheets. The Commission appreciates the CSSM modeling analyses prepared by the Companies, which have served to clarify mutual understanding, verify the functioning, and identify necessary details regarding the

[77]See CA Reply at 14.

specification and implementation of the CSSM. As noted above, the Commission notes that some details regarding implementation of the CSSM will need further clarification and refinement.[78] As part of the process to prepare and review tariffs compliant with this Decision and Order, the Companies shall prepare, review with the Consumer Advocate and Working Group as feasible, and present to the Commission example worksheets consistent with the proposed tariffs that explain and demonstrate the calculation of the CSSM parameters, including an example of a CSSM filing as would appear in the Spring Revenue Report.

In addition to approving the CSSM, the Commission instructs the Working Group to examine Blue Planet's proposal to increase the risk-sharing component of the ECRC.[79] The Commission has begun to take steps to investigate the merits of this proposal,[80] but acknowledges that this proposal could benefit from

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[78]In addition to details noted above, the Commission notes that several assumptions regarding details in the Companies' modeling analysis needed to be made that were not directly specified in the characterization of the Candidate CSSM or discussions with the Parties that will need further clarification for implementing the CSSM. Examples include the treatment of liquidated damages in the ECRC target and performance calculations, and characterization of specific resource expenses such as West Loch PV ELEP credits in the PPAC.

[79]See Blue Planet PSOP at 13 (citing "Blue Planet Foundation's Phase 2 Initial Statement of Position; Exhibits A & B; and Certificate of Service," filed on June 18, 2020, at 54-56).

[80]See PUC-HECO-IR-98, filed on May 9, 2022.

additional discussion and vetting by the Working Group before being considered. In assigning this to the Working Group, the Commission highlights the ongoing importance of ensuring that the Companies are doing everything within their power to control their fuel costs and exploring ways to diversify their fuel source portfolio, as the Commission has admonished the Companies repeatedly.

E.

AOC 5: Expedient Utilization of Grid Services from Demand-Side Resources

Upon review of the record, the Commission adopts a three-pronged approach to address this AOC: (1) the Commission will modify and extend the interim Grid Services PIM through December 31, 2023; (2) the Commission instructs the Companies to develop a Functional Integration Plan ("FIP") for DERs; and (3) the Commission instructs the Working Group to collaborate on the development of proposals for a long-term PIM that will incentivize the utilization of grid services from DERs. Together, these three steps will encourage the Companies to quickly acquire DER grid service capacity and oblige them to prepare to fully integrate grid services from DERs into system operations upon reaching operationally significant levels. Each of these is discussed in greater detail below.

Interim Grid Services PIM. The Commission will modify the existing interim Grid Services PIM by extending it for one calendar year, through December 31, 2023, as well modifying its design as follows:

- Incentives for load reduction will be increased as follows:
  - o Hawaiian Electric Load Reduction: $25.60/kW
  - o MECO Load Reduction: $70.80/kW
  - o HELCO Load Reduction: $70.80/kW

During the PIM performance period, any committed capacity newly acquired in the Oahu Scheduled Dispatch program ("SDP") and the Oahu Fast DR program, up to the 7 MW cap, shall qualify for the reward amounts above.[81] For existing and installed DER capacity that is not currently providing service to the grid under the SDP, Fast DR, or an approved Grid Services Purchase Agreement ("GSPA"), the DER shall qualify for the reward amounts if the Companies enroll the DER into, and make available through, one of these grid services programs. These DER systems are legacy resources, but not currently enrolled in any grid service program. These modifications will take effect pursuant to

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[81]The Commission granted approval for capacity committed in the Maui SDP to qualify for the PIM in Docket No. 2019-0323. See Docket No. 2019-0323, Order No. 38393, "Approving Hawaiian Electric's Request for SDP Expansion," filed on May 20, 2022, at 16-17. The Maui SDP program shall also qualify under the extended and modified PIM, as set forth above.

the new PIM tariffs and will remain in place through the extended PIM Period (i.e., through December 31, 2023).

In determining these PIM modifications, the Commission is cognizant of the urgency to procure and enroll greater amounts of capacity from DERs capable of providing grid services. In particular, these modifications reflect the critical need for peak capacity reduction that led to the approval of SDP programs on both Oahu and Maui.[82] Throughout this phase of the proceeding, two points often repeated by the Companies regarding this AOC are that there must be an operationally significant amount of DER capacity before the Companies can integrate it fully into their system operations and more experience managing DER capacity is desired to gain familiarity with its operational characteristics.[83] In modifying this PIM, the Commission recognizes that these concerns, as well as the COVID-19 pandemic, have posed challenges in achieving effective DER grid service program enrollment. This PIM is intended to support the Companies' efforts and incentivize them to overcome programmatic, operational, or other obstacles towards procuring sufficient DER capacity to set the stage for large-scale, effective DER utilization.

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[82]See Docket No. 2019-0323, Decision and Orders Nos. 37816, filed on June 8, 2021, and 38393, filed on May 20, 2022.

[83]See e.g. Companies FSOP at 136-138.

In modifying the PIM amounts for Load Reduction, the Commission recognizes that there is a critical need for peak reduction across the Companies' service territories. Additionally, the Commission approves any committed capacity newly acquired in the Oahu SDP and Fast DR programs (up to the 7 MW cap) during the PIM performance period as eligible for this PIM, as aligned with D&O 37507, which states, "grid services eligible for this PIM will be grid services acquired with approval by the Commission to broadly include, but not be limited to: (1) measures and programs approved in the DER docket[.]"[84] This modification recognizes the urgent nature of the needs that led to the approval of the SDP and Fast DR expansion and is intended to incentivize increased enrollment in such programs, thereby increasing the overall amount of grid services from DERs.

The PIM shall remain capped at a maximum financial reward of $1.5 million through 2023, with a maximum share of the financial incentive that may be awarded for grid services on Oahu of $1 million. Maintaining the existing maximum award ensures that customers are not exposed to additional risk due to the modification of this PIM, while still increasing the incentives to reduce peak load.

[84]D&O 37507 at 107.

The Commission notes that the DER Parties oppose the extension of the interim Grid Services PIM.[85] Notwithstanding the DER Parties' concerns, the Commission finds that the interim Grid Services PIM, as modified above, can still serve a valuable purpose by incentivizing the Companies to continue increasing the amount of procured capacity from DERs in anticipation of a longer-term PIM that will focus on utilization. Further, the Commission is pairing its decision to extend the interim Grid Services PIM with complementary actions, such as requiring the Companies to develop a FIP, as well as directing the Working Group to prioritize development of long-term grid services PIM proposals focusing on DER grid service utilization. Given the relatively modest extension of the interim Grid Service PIM, one year, this combined approach should ensure that the Companies are positioned to begin efficiently utilizing DERs upon the expiration of the interim Grid Services PIM.

Functional Integration Plan. The Commission shares some of the DER Parties' concerns regarding the Companies' commitment to ensuring capabilities core to the BYOD programs are timely enabled.[86] To that end, the Commission believes that increased communication from the Companies on planning for DER integration

[85] See DER Parties Post-Hearing Reply at 1-4.

[86] See DER Parties Post-Hearing Brief at 3.

is necessary. Additionally, requiring a written plan will require the Companies to directly engage with this issue and will provide a basis for evaluating their performance towards desired outcomes. Increased data and reporting will also support the development of a long-term grid services PIM. Accordingly, the Commission instructs the Companies to prepare a FIP, which shall include, at a minimum:

- Plans (steps, timelines, milestones, and projected investments/budgets) necessary to achieve the key functionalities necessary for BYOD and GSPA program resource utilization.[87]
    - Plans should address, at a minimum, which of the following are necessary for BYOD and GSPA programming and implementation:
        - Remote DER dispatch capabilities;
        - Energy management system integration and automatic dispatch;
        - Communication technologies (WiFi, cellular, network, etc.);
        - Specific advanced inverter functionalities and logistics of deploying/implementing such functionality;
        - Billing and crediting systems, including direct retail crediting for exports during grid event windows;
        - Cybersecurity requirements;

[87]To the extent these may contain confidential information, the Companies may utilize the protections afforded by the Commission's Protective Order in the relevant docket.

        - Integrated measurement/visibility of dynamic system operations and performance verification; and

        - Updates to system operations and dispatch manuals and consideration of including environmental impacts in resource dispatch.

    - For functionalities identified as necessary, the FIP shall include written commitments to have specific capabilities in place by certain dates, aligned with the DER docket requirements.

- Written commitments to transparency and information sharing, including:

    - FIP status updates;

    - Identification, in conjunction with stakeholders, of reporting metrics and frequency which may include the Companies' proposal to report monthly on all DR program availability dispatch and utilization[88];

    - A schedule of regular working group meetings with the DER Parties, the Companies' Customer Energy Resource team, the Companies' operational teams, and others as necessary; and

    - Increased transparency on any necessary RFP or other procurement processes, including key selection criteria and sharing of submitted bids to allow stakeholders to assess costs and benefits of selections.[89]

- An EM&V plan for all DER and DR Programs, which should include (at a minimum):

    - Scope and timing of evaluations;

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[88]Companies FSOP at 140.

[89]To the extent these may contain confidential information, the Companies may utilize the protections afforded by the Commission's Protective Order in the relevant docket.

- o Reporting on regular test events for programs;
- o Consideration of cost-effectiveness;
- o Customer attrition;
- o Customer load impacts;
- o Evaluation of the Companies' use and dispatch of resources; and
- o Evaluation of performance factors.

The Commission envisions the FIP serving a significant role in contextualizing and conveying the Companies' strategy, plans, and status of the transition of utility operations to better integrate and utilize cost-effective grid services from DERs, in alignment and coordination with resource planning. As the Companies' experience with DERs increases, the FIP shall be the venue through which the Companies convey its strategy and planning to expand beyond load build, load reduction, and FFR to other grid services. To the extent that the FIP should inform and connect to other existing reports, deliverables, and planning efforts - for example, grid modernization - the FIP should specify the linkage.

The Companies should work with interested Parties and stakeholders to develop the FIP, and the Commission welcomes proposed additions to the above requirements as identified by stakeholders. The FIP should also recommend an appropriate frequency for FIP updates. The Companies shall submit their FIP in the DER Docket, Docket No. 2019-0323,[90] no later than October 1, 2022. The Commission will take further action on the FIP upon its submission in Docket No. 2019-0323, where it can be reviewed in parallel with ongoing efforts to finalize the BYOD program and other related matters.

While the Commission declines to adopt a penalty mechanism for this AOC, as proposed by the DER Parties,[91] the Commission emphasizes that it views this FIP as a critical priority for the Companies, which will help facilitate the transition from the extended interim Grid Services PIM (which incentivizes procurement of grid services from DERs) to the pending long-term Grid Services PIM (which will focus on utilization of grid services from DERs). Consequently, the Commission expects a high level of commitment and performance from the Companies in developing and executing the FIP, and may initiate an investigation, with the potential assessment of penalties, if the Companies fail to comply with these requirements.

Long-term Grid Services PIM. As initially stated in D&O 37507, a PIM focused on procuring grid services from DERs is intended to be interim in nature, with the goal of establishing a

[90]The Commission notes that the DER Parties, as well as the Companies and Consumer Advocate are all parties to Docket No. 2019-0323.

[91]See DER Parties Post-Hearing Brief at 8-23.

longer-term PIM that incentivizes the Companies to utilize DERs to provide grid services.[92] Notwithstanding the Commission's decision herein to temporarily extend the interim Grid Services PIM through December 31, 2023, it remains the Commission's intent to implement a long-term Grid Services PIM focused on the utilization of DERs. To that end, the Commission directs the Working Group to focus on development of proposals for a long-term Grid Services PIM, to be submitted by July 2023.

This provides one year of additional time to gain experience with DER grid services, increase enrollment, collect additional data, and complete the Grid Needs Assessment pending in the Integrated Grid Planning docket.[93] Additionally, this timing will allow the Working Group discussion of PIM proposals to be informed and refined as the BYOD programs are rolling out.

The Commission underscores the importance of developing proposals for a PIM focused on utilization, which it views as playing a key supporting role to ensuring that progress is made toward effectively integrating DERs into the Companies' systems, and emphasizes the value of continued collaboration and progress in this area by the Working Group.

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[92]See D&O 37507 at 113.

[93]See Docket No. 2018-0165.

F.

Declining to Adopt a Modified RPS-A PIM

The Commission notes that Ulupono has proposed modifying the existing RPS-A PIM, by increasing the reward to $20/MWh for the remainder of the MRP and to $15/MWh for the subsequent MRP, as a way to address many of the Commission's AOCs.[94] While the Commission appreciates Ulupono's efforts, it does not believe that adopting a modified RPS-A would address the Commission's AOCs as effectively and directly as the suite of performance mechanisms discussed above.

While recent external events that are largely responsible for renewable project delays were unforeseen at the time the RPS-A was approved, and are not an indication of the RPS-A's effectiveness, they nonetheless illustrate the limitations of the RPS-A's ability to directly incentivize utility behavior on the issues outlined in Order No. 37969. Thus, rather than increasingly rely on the RPS-A, the Commission believes that focusing on more granular PIMs may prove more effective in addressing the Commission's AOCs, as they can be more narrowly focused on utility actions that are not as affected by external

[94] See Ulupono Post-Hearing Brief at 4-5 (stating that a modified RPS-A could address concerns regarding "reliability, interconnection times, fossil fuel plant retirements, and non-ARA cost control, as described in their respective AOCs.").

events. In this way, these PIMs will complement the RPS-A's higher-level incentive structure with a more targeted suite of incentives, which the Commission finds is more likely to be effective than simply increasing the RPS-A's reward structure.

G.

Next Steps

The Companies shall submit draft tariffs consistent with this Decision and Order within one month of this Decision and Order for the Commission's consideration. Thereafter, the Commission will issue an order addressing the Companies' draft tariffs.

In addition, the Companies shall prepare, review with the Consumer Advocate and Working Group as feasible, and present to the Commission example worksheets consistent with the proposed tariffs that explain and demonstrate the calculation of the CSSM parameters, including an example of a CSSM filing as would appear in the Spring Revenue Report.

The Working Group shall continue to serve "as a forum during the MRP to continuously introduce, examine, and vet new Performance Mechanism proposals, as well as explore modifications to existing PIMs."[95] As noted in D&O 37787, Parties are free to raise issues or submit proposals for the Group's consideration and

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[95] D&O 37507 at 162.

potential elevation to the Commission;[96] however, the Commission instructs the Working Group to prioritize the following:

A. Identifying and developing metrics to report on service reliability and the resilience of each island system to generation and T&D outages during major events;

B. Considering methodologies to calculate an incentive for the IRS PIM for non-RDG PPA projects;

C. Discussing the Companies' proposed LMI Assistance Fund component of the CSSM and developing a proposal(s) regarding the details of such a fund, including the appropriate sharing allocation, for the Commission consideration to be submitted by the end of 2022;

D. Examining Blue Planet's proposal to modify the risk-sharing component of the ECRC; and

E. Collaborating on developing proposals for a long-term PIM that incentivizes the utilization of grid services from DERs.

Additionally, the Commission observes that a number of Parties have raised proposals that have either been deemed outside the scope of this phase of the proceeding or not adopted at this time.[97] These may also be raised with the Working Group for

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[96]See D&O 37787 at 155-156.

[97]See e.g., CA Post-Hearing Brief at 27-29 (proposing modifications to the process for reviewing PIMs and SSMs); CA Statement of Position on Companies' Spring 2022 Revenue Report, filed on May 3, 2022 (Non-Docketed) at 36-39 (offering for consideration modifications to the PBR Framework's biannual review cycle); and Companies FSOP at 50-54 (proposing modifications to the existing T&D reliability PIM) and 173-190 (proposing modifications to the existing Call Center PIM and AMI Utilization PIM).

discussion and vetting and potential elevation to the Commission for consideration.

Following review of the Companies' tariffs to implement the PIMs approved above, the Commission will issue an order providing sequent details on the next steps for this proceeding, as well as for the Working Group, specifically. Briefly, the Commission envisions addressing the Companies' proposed Pilot Framework Workplan and proposed modifications to reporting requirements this summer, as well as hosting a Working Group meeting to discuss and prioritize the next slate of issues for the Working Group to address.

III.

ORDERS

THE COMMISSION ORDERS:

1. The Commission approves the Generation Reliability PIM, as set forth above.

A. The Companies shall report, if not already reported elsewhere, whether, and to what extent, generation-based service outage events are attributable to the utility or IPP-based resources.

2. The Commission instructs the Companies to develop and submit the Fossil Fuel Retirement Report, as set forth above.

3. The Commission approves the IRS PIM, as set forth above.

4. The Commission approves the CSSM, as set forth above.

5. The Commission modifies and extends the interim Grid Services PIM, as set forth above.

6. The Companies shall submit proposed tariffs for the above approved PIMs to the Commission for review within one month of this Decision and Order.

A. The Companies shall prepare, review with the Consumer Advocate and Working Group as feasible, and present to the Commission example worksheets consistent with the proposed tariffs that explain and demonstrate the calculation of the CSSM parameters, including an example of a CSSM filing as would appear in the Spring Revenue Report.

7. The Commission instructs the Companies to prepare and submit a Functional Integration Plan for DERs, as set forth above. This Plan shall be filed in the DER Docket, Docket No. 2019-0323.

8. The Commission instructs the Working Group to continue its ongoing collaborative efforts and to prioritize the following:

A. Identifying and developing metrics to report on service reliability and the resilience of each island system to generation and T&D outages during major events;

B. Considering methodologies to calculate an incentive for the IRS PIM for non-RDG PPA projects;

C. Discussing the Companies' proposed LMI Assistance Fund component of the CSSM and developing a proposal(s) regarding the details of such a fund, including the appropriate sharing allocation, for the Commission consideration, to be submitted by the end of 2022;

D. Examining Blue Planet's proposal to modify the risk-sharing component of the ECRC; and

E. Collaborating on developing proposals for a long-term PIM that incentivizes the utilization of grid services from DERs.

9. The Commission will subsequently issue an order providing further details regarding the next steps for this proceeding, including for the Working Group.

DONE at Honolulu, Hawaii June 17, 2022.

PUBLIC UTILITIES COMMISSION
OF THE STATE OF HAWAII

By James P. Griffin
James P. Griffin, Chair

By Jennifer M Potter
Jennifer M. Potter, Commissioner

By
Leodoloff R. Asuncion, Jr., Commissioner

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CERTIFICATE OF SERVICE

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